# Consequences of the Evolution of Oil and Gas Control and Production Technology in the Denver Ozone Nonattainment Area

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## ABSTRACT

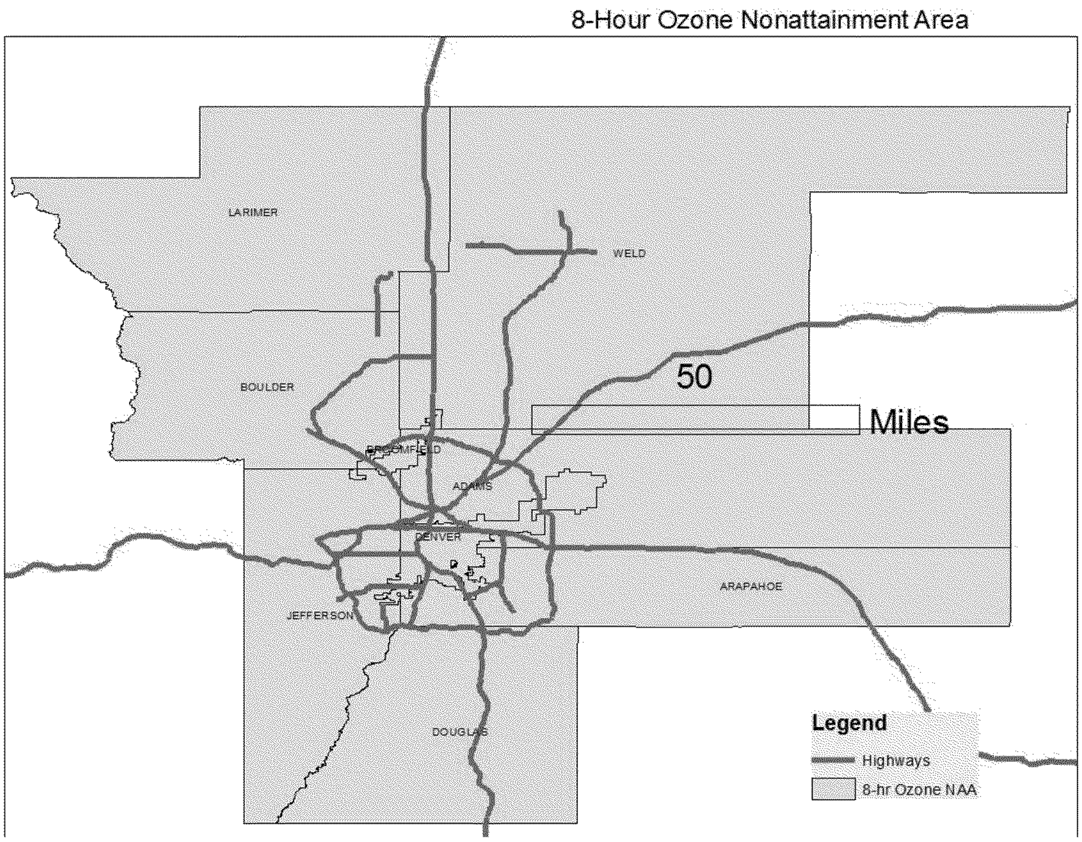
Over the last ten years, the Denver Metropolitan/North Front Range (DMA/NFR) Ozone Nonattainment Area (NAA) has seen a large increase in oil and gas production. This expansion was enabled by a change from the use of vertical wells in sandstone formations to horizontal wells in deeper shale formations that required new drilling technology. This activity together with violations of the ozone standard brought about more emission control. Calculation of emissions from these changes requires data about the chemical composition of the various oil and gas streams in combination with control technology data such as capture efficiency and rule effectiveness. Because these parameters are difficult to measure, top-down inventories are used to provide information about how the values of the parameters should be adjusted to fit ambient air measurements. Inventory development over the last decade shows how control requirements differ across political and geographic boundaries, how oil and gas activity data and emissions factors vary from state to state, and how they vary from the national average. Patterns of emission control and technology in the NAA will be compared to other oil and gas basins to illustrate the types of activities the U.S. Environmental Protection Agency (EPA) and states should be documenting on non-point oil and gas sources. The effect of the patterns on the associated data in the EPA Oil and Gas Tool will be discussed. Progress in controlling the air quality effects of increased oil and gas production can only be achieved effectively if accurate emission data are available to the public and other decision makers.

## INTRODUCTION

Since 1999, oil and gas production in the Denver-Julesburg (DJ) Basin (located in northeast Colorado) has steadily increased, except for a slight decrease between 2015 and 2016. The 1997 8-hour ozone National Ambient Air Quality Standard (NAAQS) of 80 parts per billion (ppb) was exceeded in the NAA in 2003. The area, which includes a portion of the DJ Basin, would have been designated as nonattainment in 2004, but an Early Action Compact (EAC) was implemented, and EPA deferred the nonattainment designation as long as the region continued to meet the terms of the agreement and demonstrated attainment by December 31, 2007. The NAA did not attain the standard by the end of 2007, and a full State Implementation Plan (SIP) was required by the EPA.

Condensate tank emissions were identified in the EAC inventory as the second largest source of volatile organic compounds (VOC) at 143 tons per day (tpd). Condensate tank emissions contributed about 24% of the total anthropogenic emissions, while the largest source category, on-road vehicles, contributed 30%. The EAC called for a VOC reduction in uncontrolled emissions of 47.5% for both new and existing tanks by2006. This was the single largest VOC reduction for any source category in the EAC inventory. The NAA encompasses nine counties, including the Denver Metropolitan Area and Weld County where most of the oil and gas development in the area occurs. This area, shown in Figure 1, is approximately 11,000 square miles, about the size of Massachusetts.

**Figure 1. Map of Denver Metropolitan/North Front Range (DMA/NFR) Ozone Nonattainment Area (NAA)**




The 2008 ozone SIP used base data from the year 2006 to project attainment of the 1997 80 ppb ozone NAAQS by 2010. On February 13, 2008, the EPA approved revisions to Colorado Regulation No. 7 that specified a 75% system-wide reduction of condensate tank VOC emissions from new and existing tanks for the 2007 summer ozone season. This mandate was required by May 1, 2007, with a further increased reduction to 78% for the 2012 summer ozone season using technology that could achieve a 95% reduction in VOC emissions. Photochemical modeling to demonstrate attainment met the EPA model performance criteria, and the control strategy demonstration was approved by the EPA.

EPA adopted a revised 8-hour primary and secondary ozone NAAQS of 75 ppb in 2008. The DMA/NFR NAA was designated a Marginal NAA under the 2008 ozone NAAQS and thus required to attain the 75 ppb ozone NAAQs based on 2012-2014 observed ozone air quality data. However, four monitoring sites in the DMA/NFR NAA reached 2012-2014 ozone Design Values that failed to achieve the 2008 ozone NAAQS, and the Denver Metro/NFR NAA was "bumped up" to a Moderate NAA classification. A SIP designed to demonstrate the attainment of the ozone NAAQS by July 2018 was submitted to EPA earlier this year.

The implications of the SIP requirements relating to changes in the oil and gas sector's production technology on the emissions inventory will be discussed in this paper.

## BODY

### Early Inventory Development:

The 2010 emissions inventory (projected from the 2006 base year inventory) estimate in the 2008 ozone SIP was based on a 90% system-wide emission control reduction requirement that includes all tanks owned by a single operator, providing flexibility to the operator as to which tanks to control. The emission control device was typically a flare with an assumed control efficiency of 95%. The reduction for 2010 was estimated at 24 tons per day in total condensate tank VOC emissions based on an assumed Rule Effectiveness adjustment factor of 0.83. The results of the 2010 projected inventory were based on both the above emission controls and the projected growth in oil production. The 2008 SIP inventory for condensate tanks is presented in Table 1.

**Table 1. VOC condensate tank emissions (tpd) for 2006 base and 2010 projection years**

| Emissions | Tons per Day |
|---|---|
| 2006 Base Year | 126.5 |
| 2010 Projection Year | 129.6 |

Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations, EPA-454/B-17-002, May 2017 (and the previous guidance that has been in effect for many years) states:

The general equation for emissions estimation is:

Equation (1) $E = A \times EF \times (1-ER/100)$

Where:

$E$ = emissions,

$A$ = activity total,

EF = emission factor, and
ER = overall emission reduction efficiency percent.

The ER term is the combination of the relevant percentages related to emissions controls and rules that reduce emissions, as listed in Control Data Elements.

Control Data Elements

- Control efficiency means the efficiency by which a control device or measure reduces emissions for a particular pollutant.

- Control Capture efficiency means the percentage of an exhaust gas stream actually collected for routing to a set of control devices […] In the EIS, it is a percent and should be reported as a value greater than or equal to 0.1 and less than or equal to 99.9

- Control Effectiveness means the percentage of time or activity throughput that a control approach is operating as designed, including the capture and reduction devices.

- Rule penetration means the percentage of a nonpoint source category activity that is covered by the reported control measures.

- Rule effectiveness means a rating of how well a regulatory program achieves all possible emissions reductions.

These Control Data Elements are percentages that are less than or equal to 99.9 and are multiplied together to obtain the ER term.

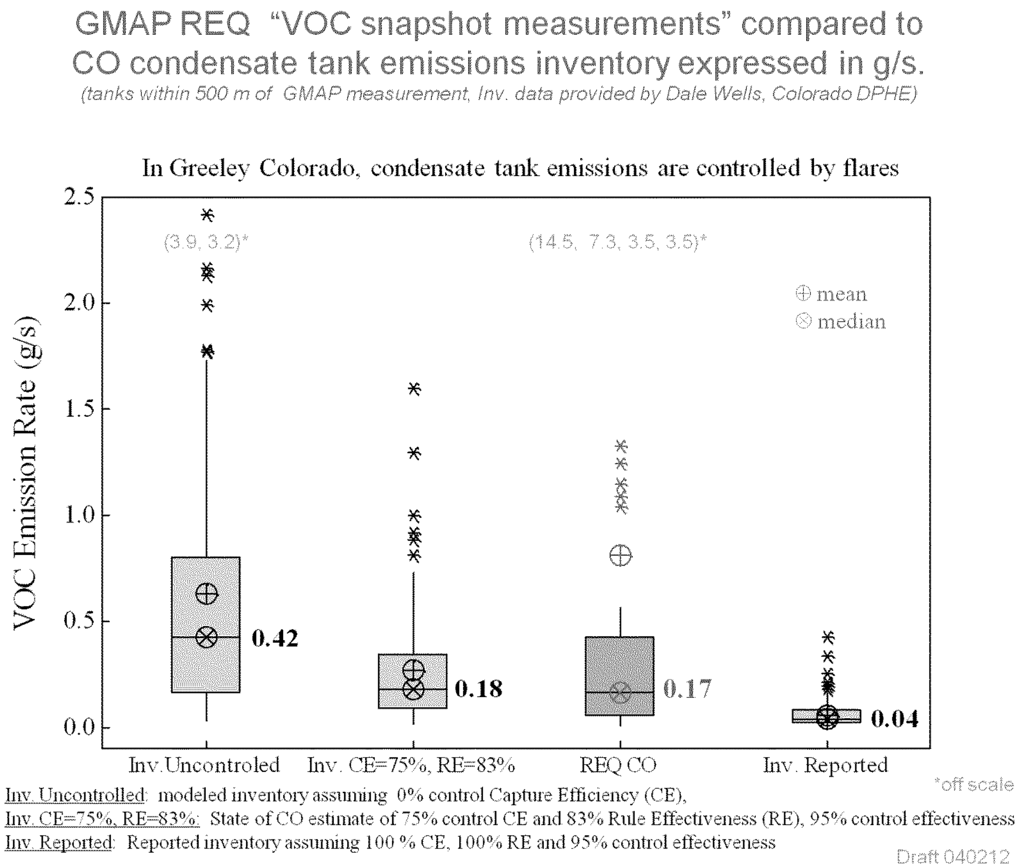
While the 2010 SIP inventory included rule effectiveness and rule penetration, it did not correctly consider control capture efficiency. Post-SIP inverse photochemical modeling indicated that there were VOC emissions missing from the inventory. Condensate tank inspections discovered open hatches and other leaks. Forward Looking Infrared Camera (FLIR) images also showed leaking condensate tanks. Additionally, a study by the National Oceanic and Atmospheric Administration (NOAA) in 2011 and another study by the EPA in 2011 indicated that the emissions from oil and gas were underestimated. Engineering judgment was used to arrive at a capture efficiency of 75%, meaning while 75% of the emissions from the tanks with control equipment were controlled, 25% of the emissions leaked into the atmosphere. A new 2008 base year post-SIP modeling inventory was created; Table 2 shows uncontrolled, reported, and adjusted emissions corrected for Rule Effectiveness (83%) and Capture Efficiency (75%) as reported in the Colorado Air Pollutant Emissions Notice (APEN) system for condensate tanks.

**Table 2. 2008 condensate tank emissions**

| Emissions | tpd |
|---:|---:|
| Uncontrolled | 351 |
| Reported | 58 |
| Adjusted | 168 |

The 2008 base year modeling incorporating the adjusted condensate tank emission estimates improved model performance. The 2008 base year modeling more correctly reflected the observed ozone concentrations compared with the 2006 base year SIP model. The upward adjustment of condensate tank emissions has been confirmed through work done by the EPA's Office of Research and Development (ORD) in a study conducted in 2012. The EPA used a vehicle fitted with measuring devices to remotely measure and calculate emissions in grams per second from 52 condensate tanks in Weld County oil and gas fields. Colorado provided estimates of uncontrolled emissions, emission reported by operators, and emission estimates adjusted for capture efficiency and rule effectiveness for those condensate tanks within 500 meters of the EPA measurement locations. The results are shown in Figure 2. The median of the ORD results (0.17 grams per second) were equivalent to the median of the Colorado emission estimates adjusted for rule effectiveness and capture efficiency (0.18 grams per second). The EPA measurements are an independent verification in addition to the modeling results that the adjusted condensate tank emissions are more valid than the emissions reported by the industry.

**Figure 2. Comparison among EPA ORD results, uncontrolled emissions estimates, adjusted emissions estimates, and reported emissions**



**Inventory Development for the 2017 Ozone SIP:**

*Base Year Inventory*

A base year of 2011 was chosen for the 2017 ozone SIP. The basic inventory approach for condensate tank emissions was as discussed above, using Equation (1) and 80% -, 75% capture efficiency, and 90% system-wide control efficiency (which incorporated rule penetration and control efficiency). Historically, emissions calculations were based on the reported throughputs in the APEN system and used reported uncontrolled emission factors adjusted for capture efficiency and rule effectiveness. However, the throughput (oil production) was changing rapidly as new wells were being drilled and old wells were declining in production. The operators were not reporting these changes, and it was decided to use the oil production reported by the Colorado Oil and Gas Conservation Commission (COGCC) along with a default emission factor of 13.7 pounds per barrel (lbs/bbl) of oil in Equation (1) and the rule effectiveness, capture efficiency, system-wide control efficiency listed above. Equation (2) describes the calculation of the 2011 condensate tank emissions:

Equation (2) Emissions (lbs) = 2011 Oil Production (bbls) X 13.7(lbs/bbl) X $(1 - (90\% \times 97.7\% \times 80\% \times 75\%))$

The 2011 condensate tank emissions are shown in Table (3) after converting to tons per day. CO and NOx emissions are from the APEN system.

**Table 3. 2011 oil and gas condensate tank emissions**

| | **2011 (tpd)** | | |
|---|---|---|---|
| Pollutant | **VOC** | **NOx** | **CO** |
| Condensate Tank Emissions | **216.0** | **1.1** | **2.3** |

Emissions from other well pad sources (Table 4) were taken from the 2011 3–State Study performed for the Western Regional Air Partnership (WRAP) by Ramboll-ENVIRON, a consulting firm. These emissions were grown from 2006 survey based data acquired for the WRAP.

**Table 4. 2011 oil and gas well pad source emissions**

| | 2011 (tpd) | | |
|---|---|---|---|
| **Oil and Gas Area Sources** | **VOC** | **NOx** | **CO** |
| Oil and Gas Area Sources | | | |
| Drill rigs | 0.7 | 11.3 | 5.9 |
| Exempt engines | 0.6 | 8.1 | 5.2 |
| Fugitives | 21.3 | | |
| Heaters | 0.1 | 1.6 | 1.3 |
| Misc. (spills, workover rigs, etc.) | 0.5 | 1.3 | 0.5 |
| Pneumatic devices | 11.8 | | |
| Pneumatic pumps | 2.4 | | |
| Truck loading of condensate liquid | 3.8 | | |
| Venting - blowdowns | 4.6 | | |
| Venting - initial completions and recompletions | 3.2 | | |
| Water tank losses | 0 | | |
| **Subtotal** | **48.9** | **22.2** | **12.9** |

The last component of the 2011 base year oil and gas inventory is the mid-stream sources such as compressor stations and natural gas processing facilities. All gas dehydration occurs at midstream facilities. These sources are reported in the APEN system and are included in the inventory as point sources, as shown in Table 5.

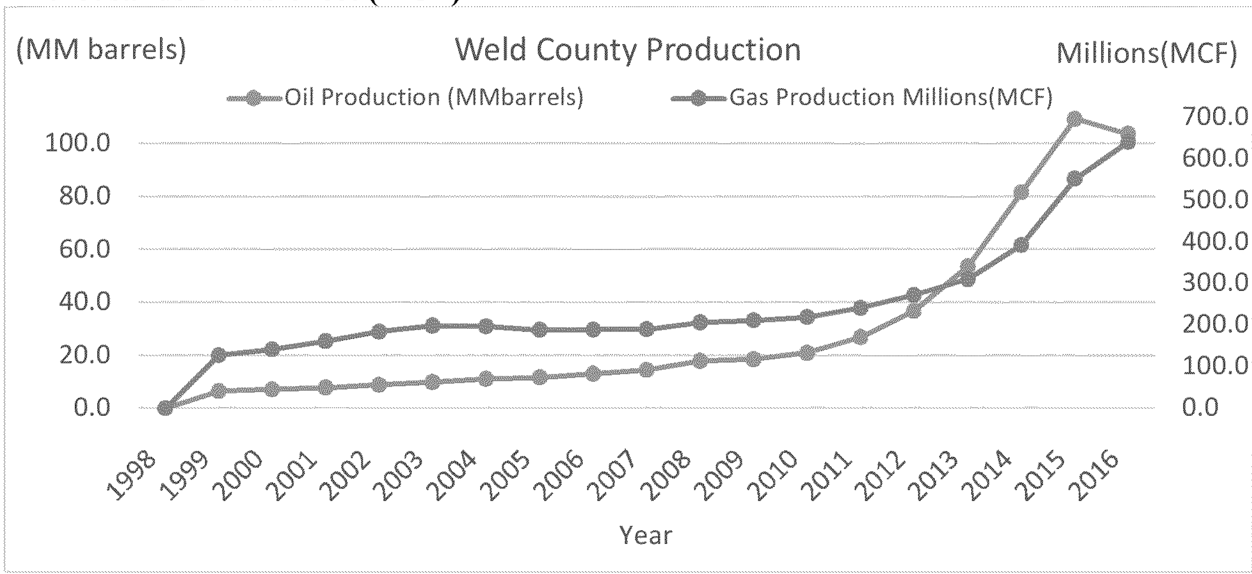
**Table 5. 2011 oil and gas point source emissions**

| 2011 (tpd) | | |
|---|---|---|
| VOC | NOx | CO |
| 14.80 | 18.10 | 17.00 |

*Attainment Year Inventory*

Up until 2013, almost all of the oil and gas production in the NAA had been from vertical wells drilled in the sandstone formations. Beginning in 2013, almost all of the new production has been in the Niobrara Shale formations, utilizing horizontal drilling and hydraulic fracturing (fracking) technology. This new production has greatly increased the rate of growth in both oil and gas. The transition to horizontal drilling has taken place at the same time as the adoption of more stringent inspection requirements for leaks and the need for more control of emissions to attain the ozone NAAQS. The increase in the rate of growth can be seen in Figure 3 with the oil and gas production totals by year in Weld County.

**Figure 3. Weld County oil and gas production by year with gas production in thousands of cubic feet (MCF)**




In 2014, the operators converted well pads and tanks associated with horizontal drilling from only one stage of separation before storage, which was the standard practice with vertical drilling, to two and three stages of separation before storage. In the case of the top two producers, a large portion of production involved tankless well pads, and now in 2017, all liquids from tankless well pads are processed at centralized facilities in pressure vessels.

In developing the attainment year inventory, Air Pollution Control Division (APCD) and Regional Air Quality Council (RAQC) staff met numerous times with the top 6 oil producers in the NAA. These producers agreed to provide their 2014 activity and emission data for all of their well pad facilities, and to project this activity and emission data to the 2017 attainment year.

We accepted the non-condensate tank data (oil and gas area sources) as submitted, but because of possible enforcement and compliance issues affecting Equation (1) parameters such as rule effectiveness, we modified the 2017 condensate tank emissions. Equation (1)

We developed uncontrolled emission factors for each of the following configuration of well pad designs based on the 2014 data submitted:

- Vertical Wells
  - 1 stage of separation
  - 2 stages of separation
- Horizontal Wells
  - Tankless
  - 1 stage of separation
  - 2 stages of separation
  - 3 stages of separation

The emission factors were developed by taking the total tons of VOC emissions (broken out by well orientation and stages of separation) and dividing the emissions by production for each of these subcategories to get an average rate of emission by subcategory. We then used Equation (1) to calculate emissions for each configuration. A 90% system-wide control requirement contained in Regulation 7 was assumed as was 83% for the product of rule effectiveness and capture efficiency for single-stage separation and 86% for the product of rule effectiveness and capture efficiency for two and three stage separation.

Of the top six producers in the NAA, one did not provide 2017 production estimates. The other five top producers did supply estimates, and did not modify them even in light of the 2016 downturn in oil prices and production. The Colorado Oil & Gas Association (COGA) and their members were consulted on future production and technology use among the remainder of the producers in the NAA. They stated that their production would be in line with that of the top producers, but that there would be no use of tankless facilities or more than two stages of separation before storage. The resulting emissions are summarized in Table 6.

**Table 6. 2017 VOC emissions inventory - oil and gas condensate Tanks**

| | Well Type | Stages of Separation | 2014 Oil Production (bbl) | 2017 Oil Production (bbl) | 2014 Uncontrolled Emissions Factors (lbs/bbl) | 2017 Uncontrolled Emissions (tpd) | Control Rate (%) | 2017 Controlled Emissions (tpd) (tpd) |
|---|---|---|---|---|---|---|---|---|
| Top 6 Producers | Horizontal | tankless | 10,217,913 | 52,247,476 | 0 | 0 | | 0 |
| | | 1 | 11,380,125 | 8,211,955 | 7.52 | 84.6 | 74.70% | 21.4 |
| | | 2 | 11,971,013 | 28,972,707 | 2.18 | 86.6 | 77.40% | 19.6 |
| | | 3 | 26,382,023 | 26,689,883 | 0.96 | 35.2 | 77.40% | 8 |
| | | **Total** | **59,951,074** | **116,122,020** | | **206.4** | | **48.9** |
| | Vertical | 1 | 6,659,910 | 5,217,456 | 9.57 | 68.4 | 74.70% | 17.3 |
| | | 2 | 2,533,845 | 1,667,938 | 7.73 | 17.7 | 77.40% | 4 |
| | | 3 | 12,732 | 0 | -- | 0 | 77.40% | 0 |
| | | **Total** | **9,206,486** | **6,885,393** | | **86.1** | | **21.3** |
| | **TOTAL** | | **69,157,560** | **123,007,413** | | **292.4** | | **70.2** |
| Remainder of Producers | Horizontal | 1 | 2,051,556 | 1,641,245 | 6.03 | 13.6 | 74.70% | 3.4 |
| | | 2 | 8,206,224 | 17,747,313 | 1.74 | 42.3 | 77.40% | 9.6 |
| | | **Total** | **10,257,780** | **19,388,558** | | **55.9** | | **13** |
| | Vertical | 1 | 1,102,678 | 882,142 | 10.27 | 12.4 | 74.70% | 3.1 |
| | | 2 | 472,576 | 378,061 | 7.61 | 3.9 | 77.40% | 0.9 |
| | | **Total** | **1,575,254** | **1,260,203** | | **16.4** | | **4** |
| | **TOTAL** | | **11,833,034** | **20,648,761** | | **72.2** | | **17** |
| All Producers in 9-County Area | Horizontal | tankless | 10,217,913 | 52,247,476 | 0 | 0 | | 0 |
| | | 1 | 13,431,681 | 9,853,200 | 7.27 | 98.1 | 74.70% | 24.8 |
| | | 2 | 20,177,237 | 46,720,020 | 2.01 | 128.9 | 77.40% | 29.1 |
| | | 3 | 26,382,023 | 26,689,883 | 0.96 | 35.2 | 77.40% | 8 |
| | | **Total** | **70,208,854** | **135,510,578** | | **262.2** | | **61.9** |
| | Vertical | 1 | 7,762,587 | 6,099,598 | 9.67 | 80.8 | 74.70% | 20.4 |
| | | 2 | 3,006,421 | 2,045,998 | 7.71 | 21.6 | 77.40% | 4.9 |
| | | 3 | 12,732 | 0 | -- | 0 | 77.40% | 0 |
| | | **Total** | **10,781,740** | **8,145,596** | | **102.4** | | **25.3** |
| | **TOTAL** | | **80,990,594** | **143,656,174** | | **364.6** | | **87.2** |

The oil and gas area source emissions submitted by the top 6 producers were scaled to the NAA by well count and oil production as appropriate. Separator emissions, water tank emissions, truck loadout, and oil tank emissions were scaled to the rest of the producers by oil production, and all other oil and gas area source emissions were scaled by well count (oil production and well counts were derived from COGCC data). Table 7 provides the oil and gas area source inventory for the NAA.

**Table 7. 2017 oil and gas area source emissions**

| | VOC (tpd) | NOx (tpd) | CO (tpd) |
|---|---|---|---|
| **Separator Control** | 12.4 | | |
| **Water Tank Control** | 1.4 | 0 | 0.1 |
| **Well Unload Total** | 3.9 | | |
| **Burner** | 0.4 | 7.8 | 6.5 |
| **Pneumatic Pump** | 0.4 | | |
| **Loadout Control** | 8.4 | 0 | 0.1 |
| **Pneumatic Controller Low Bleed** | 0.1 | | |
| **Pneumatic Controller Intermittent** | 21.5 | | |
| **Drilling** | 1.4 | 13.6 | 5.1 |
| **Venting Completions** | 0.7 | 0.1 | |
| **Fracing Completions** | 0.9 | 13.5 | |
| **Engines** | 3.8 | 12.9 | 22.5 |
| **Misc. (spills, workover rigs, etc.)** | 0.6 | 1.4 | 0.6 |
| **TOTAL (w/o Fugitives)** | 55.9 | **49.4** | **34.8** |
| **NAA 2017 Total Fugitive** | 50.5 | **44.6** | **31.4** |
| **Controlled Fugitives in NAA (tpd) (EPA RACT - 60%)** | **8.5** | | |
| **TOTAL 2017 NAA** | **59** | **44.6** | **31.4** |

The 2017 attainment year point source inventory was grown from 2014 APEN emissions by oil production (the mid-stream sources such as compressor stations and natural gas processing facilities).

These sources are reported in the APEN system and are included in the inventory as point sources, and are shown in Table 8.

**Table 8. 2017 oil and gas point source emissions**

| 2017 (tpd) | | |
|---|---|---|
| **VOC** | **NOx** | **CO** |
| **16.30** | **20.60** | **19.70** |

The entire 2011 base year and 2017 attainment year inventories used in the 2017 Ozone SIP is shown in Table 9.

**Table 9. Summary of 2011 and 2017 planning emissions (tons per day) in the ozone NAA**

| Description | 2017 | | | 2011 | | |
|---|---|---|---|---|---|---|
| | VOC | $NO_X$ | CO | VOC | $NO_X$ | CO |
| **Oil and Gas Sources** | | | | | | |
| **Point Sources Subtotal** | 16.3 | 20.6 | 19.7 | 14.8 | 18.1 | 17 |
| **Condensate Tanks Subtotal** | 78.7 | 0.6 | 2.3 | 216 | 1.1 | 2.3 |
| **Area Sources Subtotal** | 59 | 44.6 | 31.4 | 48.9 | 22.2 | 12.9 |
| **TOTAL** | 154 | 65.8 | 53.4 | 279.7 | 41.4 | 32.2 |
| **Point Sources (EGU and Non-Oil and Gas)** | | | | | | |
| **Electric Generating Units (EGU)** | 0.4 | 19.2 | 2.9 | 0.7 | 39.7 | 3.6 |
| **Point (Non-Oil and Gas)** | 28 | 20.9 | 14.4 | 25.9 | 21 | 14.1 |
| **TOTAL** | 28.4 | 40.1 | 17.3 | 26.5 | 60.7 | 17.7 |
| **Area Sources (Non-Oil and Gas)** | | | | | | |
| **TOTAL** | 67.5 | - | 1.6 | 60.6 | - | 1.4 |
| **Non-Road Mobile Sources** | | | | | | |
| **TOTAL** | 44.3 | 54.9 | 759.7 | 58.2 | 75.9 | 800.2 |
| **On-Road Mobile Sources** | | | | | | |
| **Light-Duty Vehicles** | 52.4 | 50.3 | 538.6 | 90 | 102.5 | 812.2 |
| **Medium/Heavy-Duty Vehicles** | 2.6 | 23 | 16.2 | 3.7 | 39.6 | 20.6 |
| **TOTAL** | 55 | 73.3 | 554.7 | 93.7 | 142 | 832.8 |
| **Total Anthropogenic Emissions** | 349.2 | 234 | 1,386.6 | 518.8 | 320 | 1,684.4 |
| **Total Biogenic Sources** | 170.5 | 6.1 | 21.6 | 170.5 | 6.1 | 21.6 |
| **Total Nonattainment Area Emissions** | **519.7** | **240.1** | **1,408.2** | **689.3** | **326.1** | **1,706.0** |

Comparison with Top-Down Inventories:

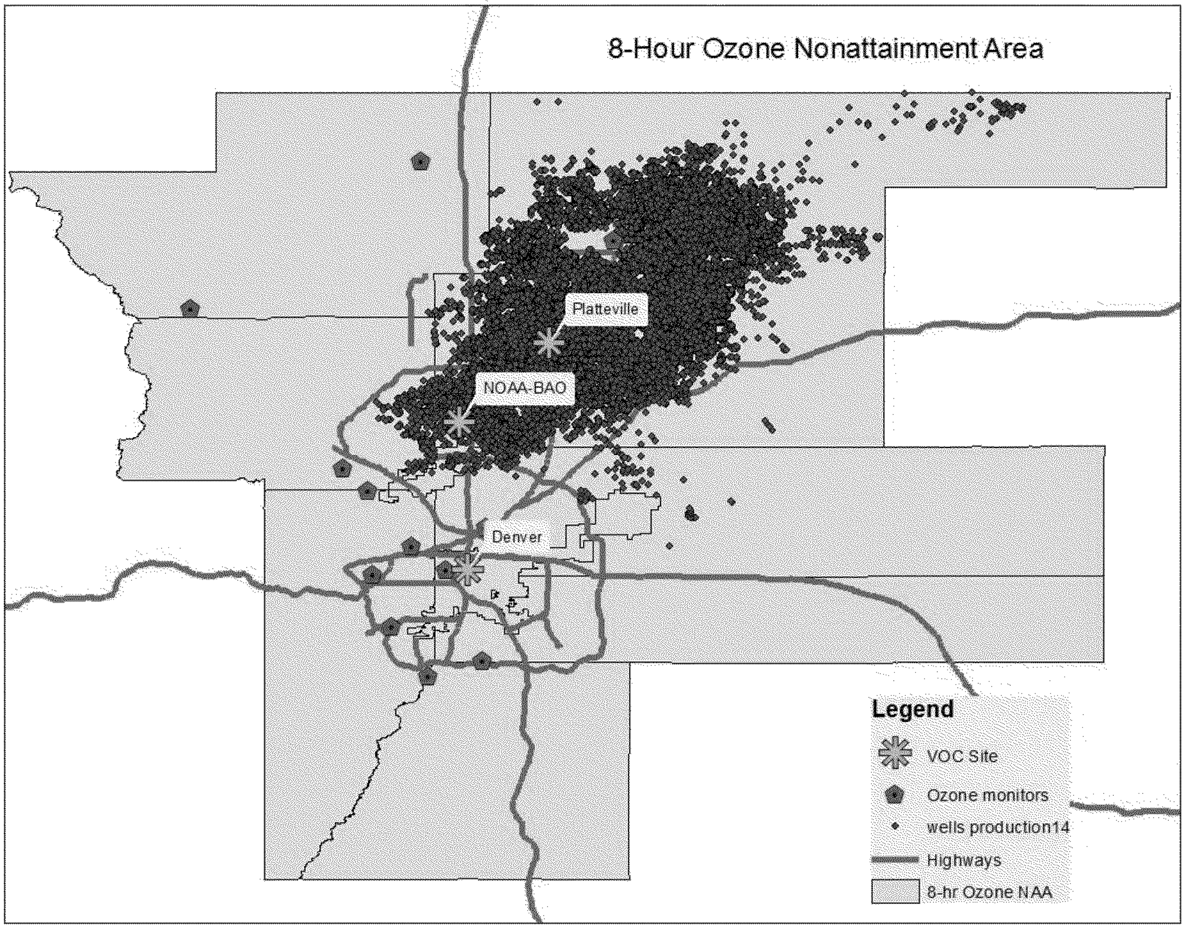
The 2008 ozone SIP inventory was adjusted and remodeled based in part on a top-down inventory in a study done by NOAA in 2012. This NOAA inventory indicated that oil and gas VOC emissions were underestimated by about a factor of two. We developed a new 2008 base year inventory that had condensate tank VOC emissions that were about three times larger than those reported by industry (see Table 2 above). Since that time, a new top-down inventory for 2012 published in 2013 by NOAA, indicates that the 2017 ozone SIP base year inventory may also underestimate oil and gas VOC emissions by a factor of two or more, and that benzene emissions may be underestimated by a factor of 7.

This is concerning, but APCD has been measuring 6 to 9 AM 3-hour samples of VOC species using Summa canisters at Platteville and Denver since 2012. These data are good indicators of the primary VOC species emitted by local sources in these two areas since a) mixing is limited at those early hours and b) the sun angle and temperatures are low so little photochemical reaction is occurring. An analysis of this data set is probably a more robust way to determine the accuracy of the VOC inventory.

VOC Precursor Analysis:

Figure 4 shows the VOC sample locations in the NAA. As can be seen, the Platteville site is in the midst of the oil and gas operations, and the Denver site is in an urban location. Note that NOAA has also done long term sampling at the Boulder Atmospheric Observatory (BAO) Tower on the fringe of the oil and gas area.

**Figure 4. VOC sample locations**




Figures 5 and 6 show local maps of the two APCD sites. The two maps are at the same scale. The highway running north and south in Figure 5 is US 85. The Denver site in Figure 6 has two interstates, I25 (north to south) and I 70 (east to west). The Denver site is in the middle of the central business district next to several roadways.

**Figure 5. Platteville VOC site**

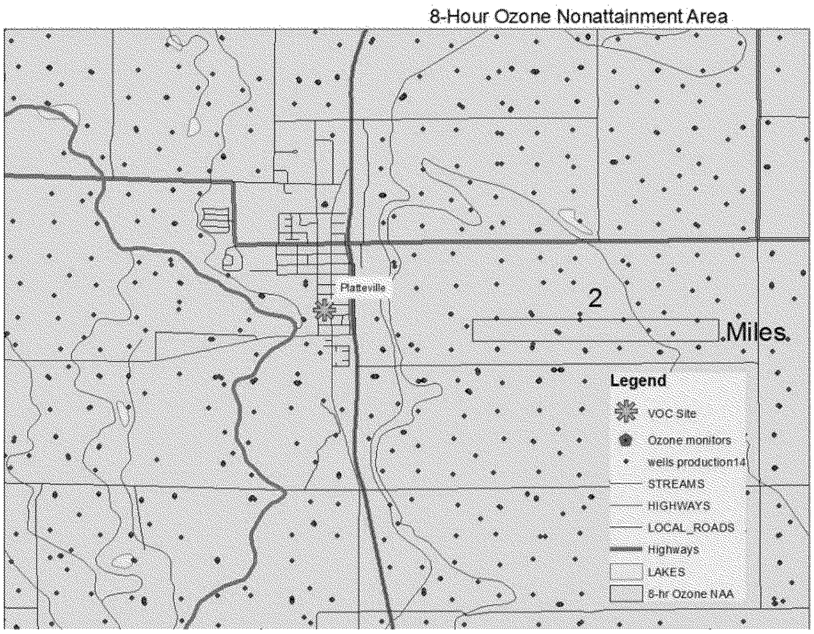
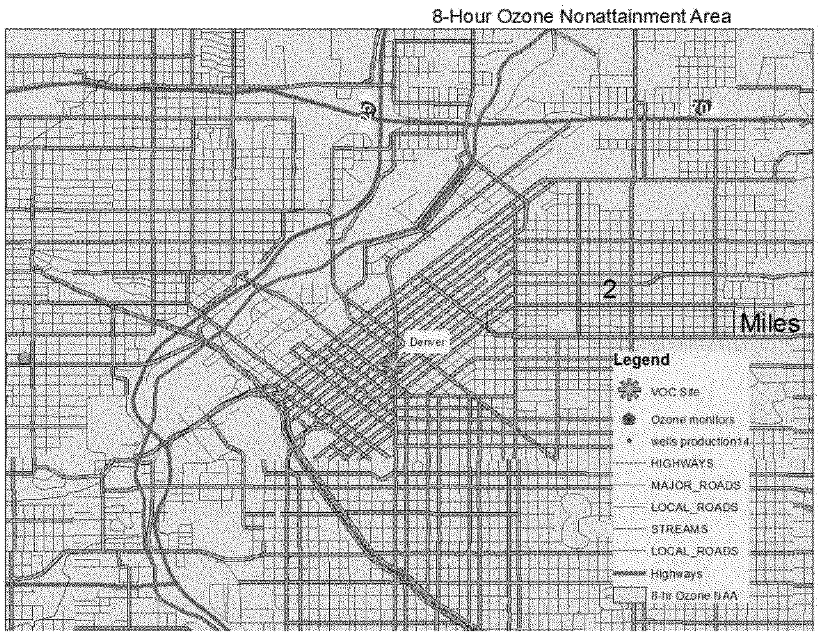
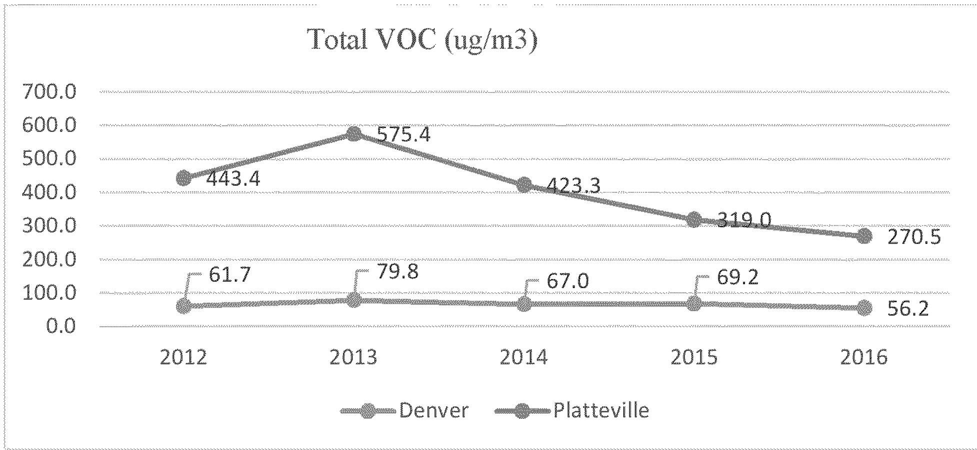



**Figure 6. Denver VOC site**



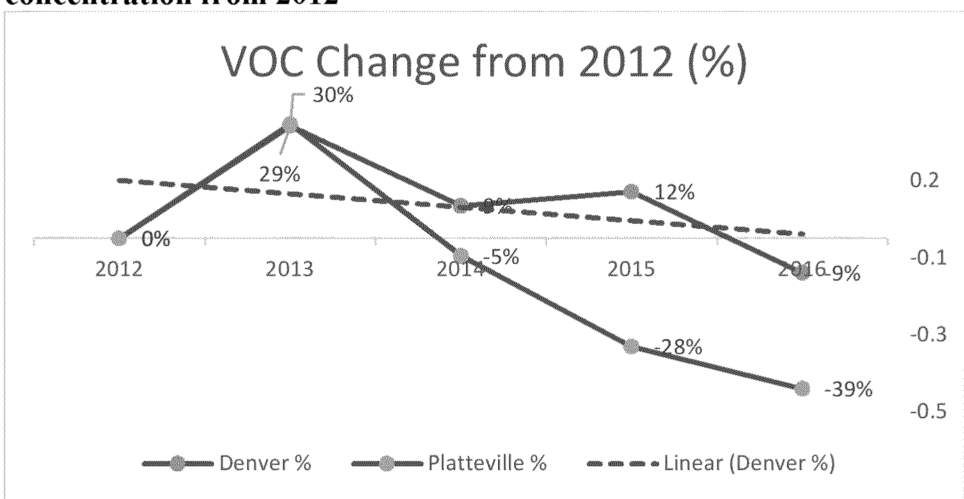
The annual average VOC in ug/m3 at the Platteville and Denver sites is shown in Figure 7.

**Figure 7. Annual average VOC at Platteville and Denver sites from 2012 to 2016**




The concentrations are much higher in Platteville, and there is a pronounced downward trend between 2013 and 2016 in Platteville but not in Denver. In this precursor analysis, we will examine the change in precursor emissions and concentrations from the 2012 baseline year which was when the wells were almost all vertical. After the year 2012 wells were almost all horizontal. The percentage change in concentrations from 2012 is shown in Figure 8.

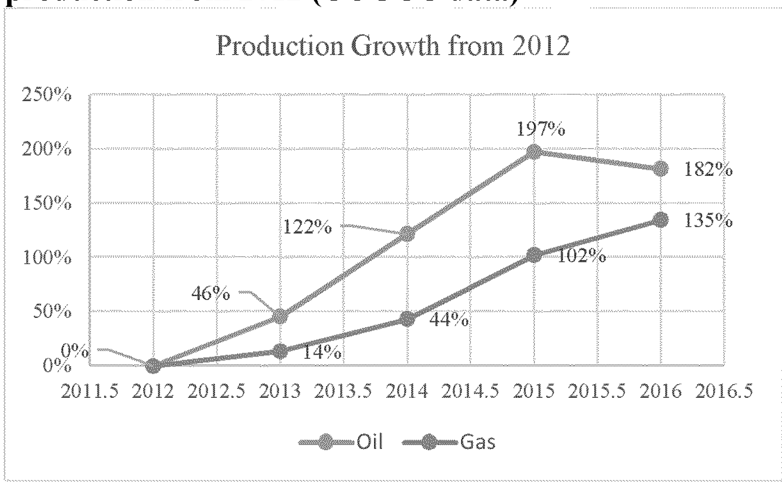
**Figure 8. Percentage change in VOC concentration from 2012**




The Denver site shows a flat but very slight downward trend. The Platteville site has a 16.8 % increase in concentration from 2012 to 2013 and a consistent downward trend to a 42.5% decrease in concentration from 2012 in 2016.

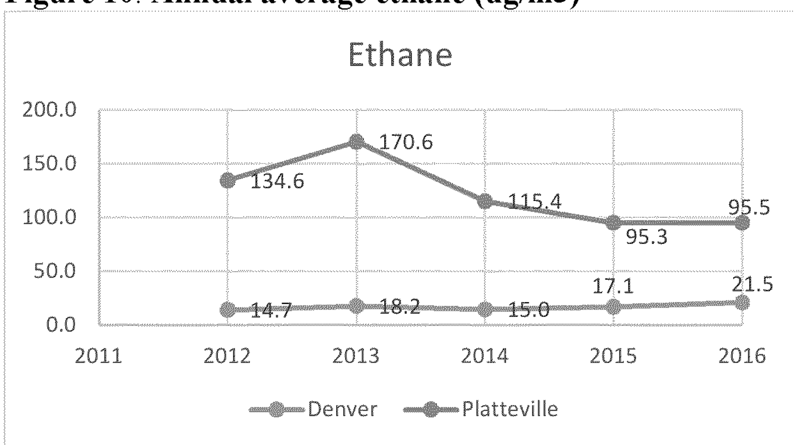
The relative growth in oil and gas production in Weld County from 2012 to 2016 is shown in Figure 9.

**Figure 9. Percent change in Weld County oil and gas production from 2012 (COGCC data)**




As discussed previously in the Attainment Year Inventory section, 2013 was a transition year to horizontal drilling and fracking. The 46% increase in oil production from 2012 to 2013 shown in Figure 9 resulted in an increase of 30% in VOC shown in Figure 8. The control technology, one stage of separation before storage, remained unchanged. However, from 2014 and later the increase in production does not result in an increase in VOC emissions. Instead, as the control of new production changes to two and three stages of separation before storage, VOC emission levels declined by 36% in 2015 and 39% in 2016. Figure 10 shows the annual average ethane concentrations from 2012 to 2016.

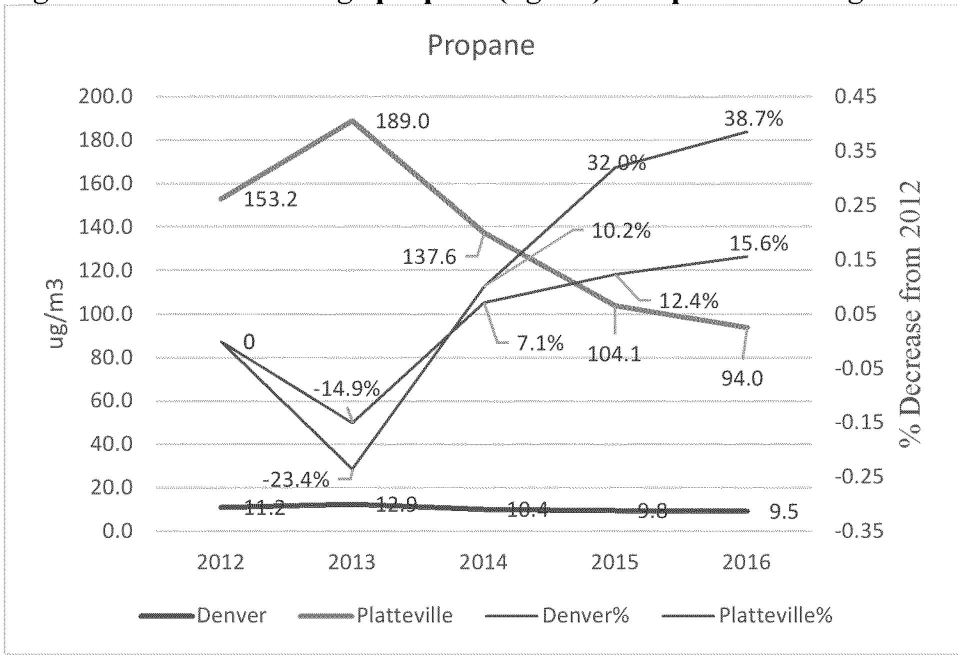
**Figure 10. Annual average ethane (ug/m3)**




It is interesting that while VOC levels declined from 2015 to 2016, ethane levels slightly increased, suggesting that the increase in gas production overcame the decrease in oil production for ethane but not for VOC.

Figure 11 shows the annual average propane concentrations from 2012 to 2016 and the percent change in concentration from 2012. A percent decrease in concentration is shown as a positive number while a percent increase in concentration is shown as a negative number.

**Figure 11. Annual average propane (ug/m3) and percent change from 2012**




Propane follows the trend of total VOC concentrations. The concentration declines between 2015 and 2016, suggesting that the decline in oil production overcame the increase in gas production. Propane is present at a higher percentage in condensate emissions than in gas venting emissions, while the opposite is true of ethane.

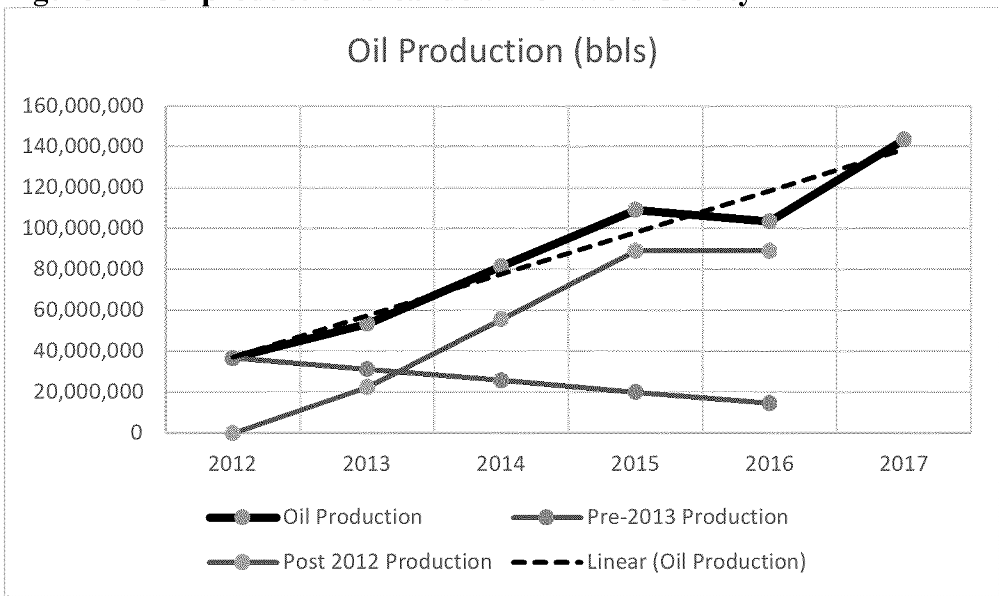
The WRAP has collected data from operators in western oil and gas basins and developed speciation profiles for flash gas (DJFLA) and vent gas (DJVNT). These profiles for the DJ Basin are compared with the Platteville site in Table 10. They help to explain the trend in concentration in light of the trend in oil and gas production. Flash gas is proportional to oil production while vent gas is proportional to gas production. Table 10 shows the WRAP DJ Basin speciation profiles compared with speciation profiles from VOC sampling at the APCD sites and the NOAA BAO site. Table 10 also has percentages for the same species and years for the Denver site for comparison to Platteville. In 2012, the Platteville profile agrees well with the DJ flash profile for the 6 most abundant pollutants. Denver and the BAO sites have more ethane than propane. Acetylene is associated with combustion and is not present in the DJ WRAP profiles, and acetylene is a much higher percentage of total non-methane organic compounds (NMOC) at Denver than Platteville or BAO. The APCD site NMOC percentages do not add to 100% because there are more pollutants at those sites than shown in Table 10.

**Table 10. NMOC speciation profiles by weight percent**

| | | | | Platteville | | | Denver | | |
|---|---|---|---|---|---|---|---|---|---|
| DJFLA | DJVNT | NOAA BAO | Species | 2012 | 2015 | 2016 | 2012 | 2015 | 2016 |
| 32.6% | 24.7% | 22.4% | Propane | 26.5% | 25.1% | 25.7% | 16.5% | 13.2% | 13.4% |
| 26.9% | 45.3% | 27.2% | Ethane | 23.3% | 23.0% | 26.1% | 21.6% | 22.9% | 30.4% |
| 15.0% | 9.7% | 18.6% | n-Butane | 16.1% | 15.4% | 15.1% | 10.7% | 9.3% | 9.9% |
| 8.3% | 5.1% | 8.0% | Isobutane | 6.9% | 6.3% | 6.7% | 4.3% | 4.3% | 3.9% |
| 4.6% | 3.7% | 7.7% | n-Pentane | 6.6% | 6.5% | 5.9% | 6.2% | 6.7% | 4.4% |
| 5.9% | 4.1% | 6.9% | Isopentane | 7.1% | 5.8% | 5.5% | 8.2% | 0.1% | 3.6% |
| | | 2.5% | Methylcyclopentane | 0.9% | 1.2% | 0.9% | 1.4% | 1.8% | 1.3% |
| 3.3% | 7.1% | 2.2% | n-Hexane | 2.1% | 2.6% | 2.1% | 2.8% | 3.0% | 2.3% |
| 2.5% | 0.0% | 0.7% | n-Heptane | 0.6% | 0.9% | 0.8% | 1.0% | 1.4% | 1.3% |
| 0.2% | 0.2% | 0.6% | Toluene | 0.5% | 0.9% | 0.8% | 3.5% | 5.8% | 4.7% |
| 0.2% | 0.1% | 0.5% | Benzene | 0.5% | 0.5% | 0.5% | 1.7% | 1.6% | 1.7% |
| | | 0.6% | Methylcyclohexane | 0.7% | 1.1% | 0.8% | 0.9% | 0.8% | 0.5% |
| | | 0.6% | Cyclohexane | 0.7% | 0.9% | 0.7% | 0.9% | 3.1% | 2.1% |
| | | 0.5% | Acetylene | 0.2% | 0.4% | 0.5% | 2.4% | 2.6% | 2.9% |
| | | 0.5% | Ethylene | 0.5% | 0.6% | 0.7% | 5.0% | 4.7% | 4.4% |
| 0.1% | 0.1% | 0.3% | m/p Xylene | 0.2% | 0.4% | 0.3% | 1.8% | 2.5% | 1.8% |
| 0.1% | 0.0% | 0.2% | 2,2,4-Trimethylpentane | 0.0% | 0.0% | 0.1% | 0.7% | 1.2% | 0.9% |
| | | 0.1% | o-Xylene | 0.1% | 0.1% | 0.1% | 0.7% | 1.1% | 0.7% |
| 0.1% | 0.0% | 100.0% | n-Nonane | 0.1% | 0.2% | 0.1% | 0.3% | 0.5% | 0.4% |
| 0.0% | 0.0% | | n-Decane | 0.0% | 0.2% | 0.1% | 0.4% | 0.6% | 0.4% |
| 0.0% | 0.0% | | Ethylbenzene | 0.1% | 0.1% | 0.1% | 0.6% | 0.9% | 0.6% |
| 0.4% | 0.0% | | n-Octane | 0.2% | 0.5% | 0.3% | 0.5% | 0.7% | 0.6% |
| 0.0% | 0.1% | | Cyclopentane | 0.4% | 0.4% | 0.3% | 0.5% | 0.6% | 0.4% |
| 100.0% | 100.0% | | | | | | | | |
| | | | 2-Methylpentane | 1.8% | 1.8% | 1.7% | 2.9% | 2.9% | 2.1% |
| | | | 3-Methylhexane | 0.4% | 0.5% | 0.4% | 1.2% | 1.9% | 1.5% |
| | | | 3-Methylpentane | 1.0% | 1.0% | 0.9% | 1.7% | 1.5% | 1.1% |
| | | | 2-Methylhexane | 0.4% | 0.6% | 0.4% | 1.3% | 3.8% | 2.5% |
| | | | 2,3-Dimethylbutane | 0.2% | 0.3% | 0.3% | 0.5% | 0.5% | 0.4% |
| | | | SUBTOTAL | 98.1% | 97.3% | 98.1% | 88.7% | 86.5% | 90.9% |

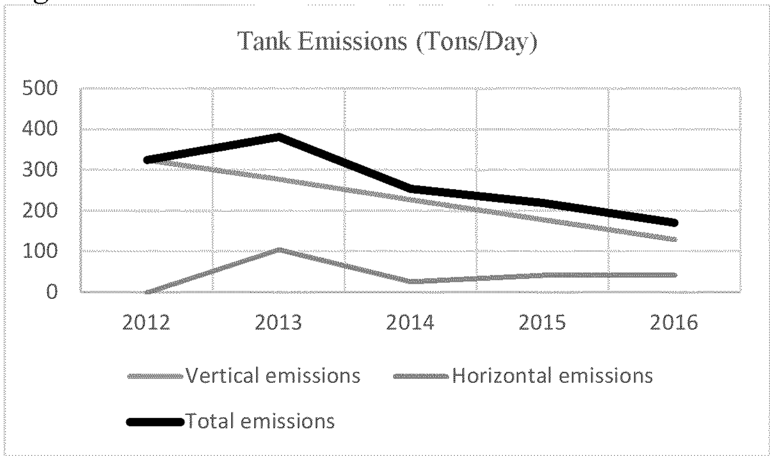
The trend in oil production can be broken down into two parts, the new post-2012 horizontal production in shale and the old pre-2013 vertical production in sandstone. Because wells decline in production over time, the pre-2013 production is declining, and the new post-2012 production is increasing due to new drilling. Figure 12 shows the production broken into these two parts along with the total production. The total production used in the 2017 attainment inventory is also shown, as well as the post 2012 oil production linear trend line. The SIP 2017 oil production prediction is close to the trend line. The SIP 2012 production estimate is for the whole NAA, but over 80% of the production is in Weld County.

**Figure 12. Oil production breakdown for Weld County**



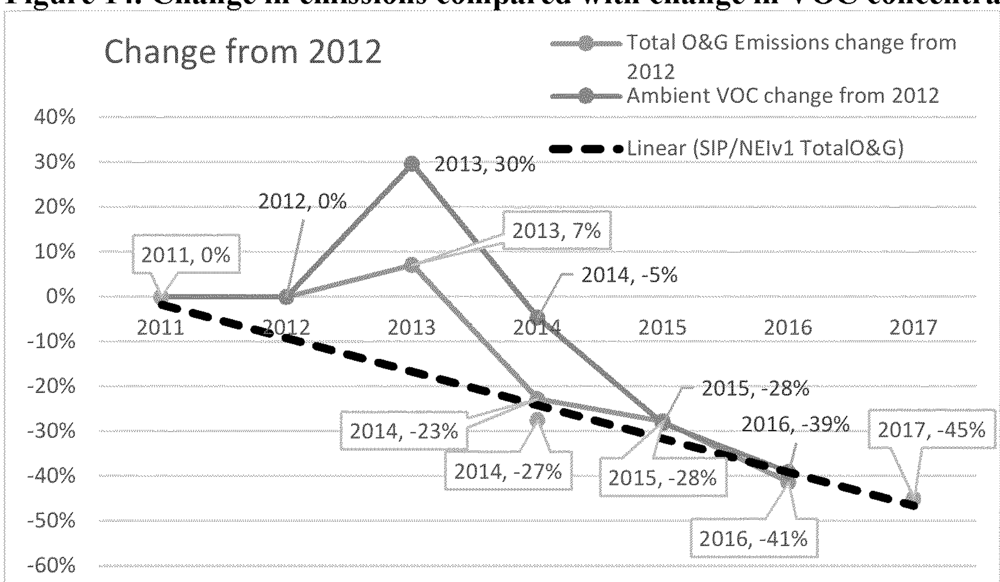

As stated earlier, operators used only one stage of separation before storage in 2012 and 2013, and since then have used two and three stages of separation or have used tankless facilities. If we divide the total controlled emissions for horizontal wells by the total production from all producers from Table 6, we can obtain a post-2013 controlled horizontal emission rate of 0.33 pounds per barrel. For 2012, we use Equation (2) to calculate vertical well emissions using the 2012 oil production. For 2013 and later, we use Equation (2) to calculate horizontal well emissions using 2013 production with an emission rate of 7.27 pounds per barrel (from the horizontal emission rate using one stage of separation for all producers in Table 6) instead of 13.7 pounds per barrel for 2013 only (the 0.33 pound per barrel rate is used for 2014 and later). Tank emissions broken out for pre-2013 production and post-2012 production are shown in Figure 13.

**Figure 13. Tank VOC emissions**




The percent change in total oil and gas emissions from 2012 along with the percent change in ambient 6 to 9 AM VOC precursor concentrations at Platteville is shown in Figure 14. The tank emissions were combined with the oil and gas point and area sources (adjusted by year by the ratio of oil production) from Table 9 and are also shown as the SIP total oil and gas inventory change from 2011 to 2017. The Colorado submitted total oil and gas 2014 NEI version 1 change from the 2011 SIP estimate, and the 2017 total oil and gas inventory estimated change form 2011are also shown with the linear fitted curve. As can be seen, the time series of reductions track very well except that the increase in VOC concentrations (30%) between 2012 and 2013 is much greater than the increase in emissions for the same period (7%). This indicates that the 2013 uncontrolled flash emission factor is much greater than the 7.27 pounds per barrel we have assumed (and probably the capture efficiency is less). This uncontrolled emission factor is not used after 2013 however, since the flash emissions are removed by the multiple stages of separation before going into the condensate tanks. After 2013 the emission trend slope tracks the ambient VOC slope reasonably well.

**Figure 14. Change in emissions compared with change in VOC concentrations**



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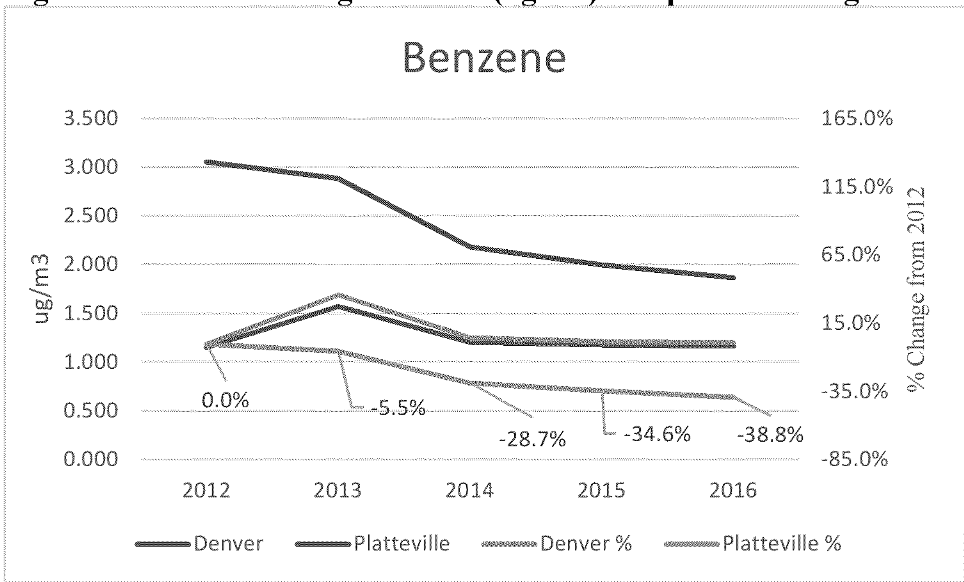
The 2012 top-down inventory by NOAA indicates that Benzene is a factor of 7 higher than the bottom up inventory. The trend in benzene emissions is shown in Figure 15.

**Figure 15. Annual average benzene (ug/m3) and percent change from 2012**




The ambient annual benzene trend differs from that of VOC. Benzene decreases slightly from 2012 to 2013 in Platteville. With tank controls, it is 38.8% lower than 2012 levels in 2016. This indicates that the flash emissions have decreased. Benzene is significantly higher in Platteville than in Denver despite the fact that there are much more benzene emissions from gasoline fueled motor vehicles in Denver. If we subtract ethane from the NMOC 2012 profile for Platteville in Table 10 and calculate the percent benzene of VOC, we get 0.69% (by contrast, the WRAP VOC percentage of benzene is 0.21% for flash and 0.24% for vent). Applying this percentage to the total oil and gas 2011 emissions from Table 8 of 279.7 tons per day and adjusting for the 2012 oil production, we get 1.9 tons per day or 100 kilograms (kg) per hour. The top-down inventory arrived at a 2012 total of 173 kg per hour. Given the analysis in this section, 100 kg per hour is more reasonable. In 2016, the percentage of VOC at Platteville stayed the same, and applied to the 2017 estimated oil and gas emissions of 154 tons per day would decrease benzene emissions to 1.1 tons per day or 40 kg per hour, cutting benzene levels by 60%. Denver saw a slight increase in benzene levels in 2013, but this was probably due to a change in gasoline composition rather than a change in the condensate or gas profile.

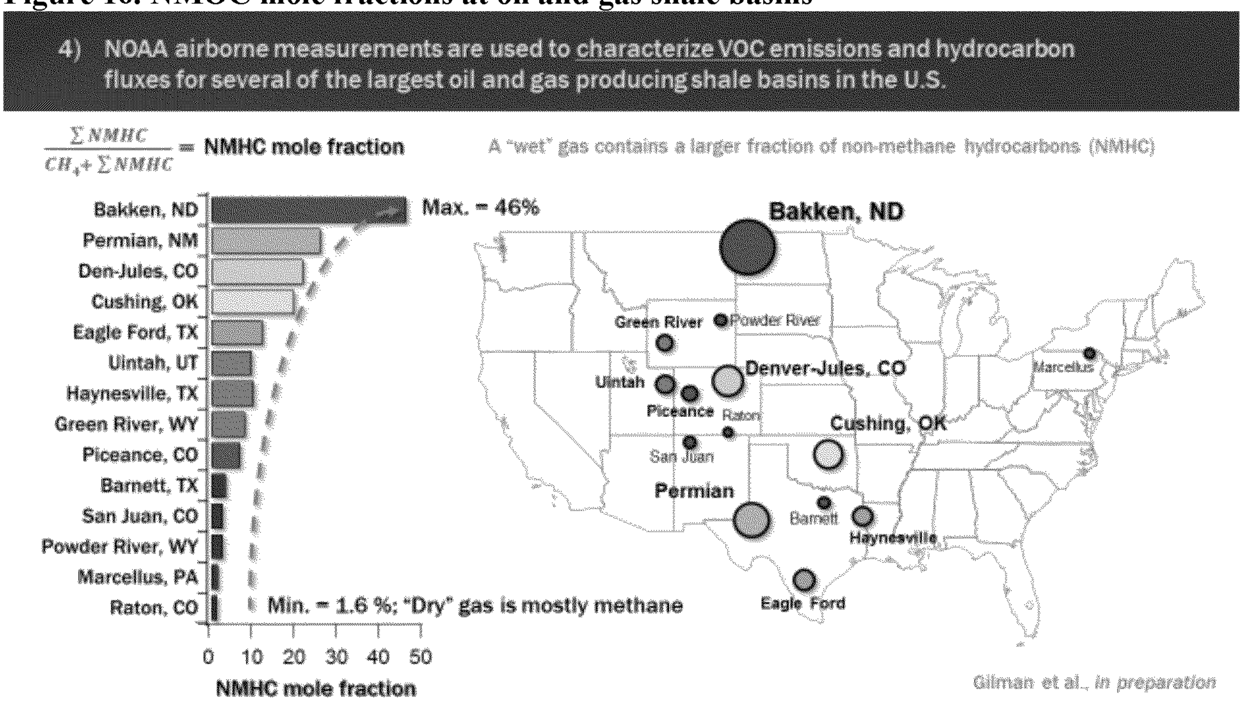
## CONCLUSIONS

Based on the VOC precursor analysis, particularly as represented by Figure 14, the 2017 SIP base year and attainment inventories are reasonable. The top-down inventory conclusions that the base year inventory may be twice as high for VOC and seven times as high for benzene do not seem to match the ambient precursor data. The WRAP speciation profile for benzene in flash emissions does seem to be low by a factor of three. As shown in Table 9, condensate tank emissions are the largest single category of VOC, and controlling them provides over 80% of the total reduction in emissions from 2011 to 2017. If there were some other unknown or poorly characterized source of VOC emissions, the ambient VOC trend would not have tracked the total oil and gas emission trend as well since tank emissions are the component responsible for nearly all of the emission reductions. Benzene concentrations track the VOC concentrations, and are related to the same sources. Ambient VOC, benzene concentrations and oil and gas emissions have decreased steadily since 2013 in spite of large increases in oil and gas production.

Condensate emissions are large in the NAA because both oil and gas are produced in the same wells under conditions of high gas pressure resulting in high flash emissions rates. Flash emissions are from gases dissolved in the oil that "flash" out of solution when the gas pressure is reduced to near ambient levels. The use of two or three stages of separation usually combined with the use of compressors (to lower the pressure in the separators) allows most of the flash gas to be removed from solution before going into storage. Oil or condensate in conjunction with high pressure gas is a subset of "wet gas".

NOAA has been performing aircraft sampling over many of the shale oil and gas basins in the U.S. to characterize emissions, and a summary of their findings is shown in Figure 16.

**Figure 16. NMOC mole fractions at oil and gas shale basins**




The basins that rank above the San Juan in Figure 16 may have very significant condensate tank emissions, as indicated by the increasing levels of NMOC fractions. To quantify these emissions, pressurized liquid samples should be obtained from the well pad separators to calculate a valid uncontrolled emission rate. Without such samples the EPA Oil and Gas Tool will not adequately represent emissions. Good speciation profiles are also necessary to realistically apportion VOCs for hazardous air pollutants and photochemical models. Ambient

Summa canister sampling is a good check on the pressurized liquid samples, which are difficult to characterize correctly.

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